BEFORE THE
ILLINOIS COMMERCE COMMISSION

IN THE MATTER OF: )
)
ELECTRIC POLICY COMMITTEE MEETING )

Chicago, Illinois
April 11, 2002

Met pursuant to notice at 1:30 p.m.

BEFORE:

TERRY HARVILL, COMMISSIONER

RUTH KRETSCHMER, COMMISSIONER

MARY FRANCIS SQUIRES, COMMISSIONER

(telephonically)

APPEARANCES:

MS. ARLENE A. JURACEK
Vice President, Regulatory and Strategic Services for Commonwealth Edison Company;

MR. MICHAEL M. SCHNITZER
Vice President, Transmission Operations and Planning, Commonwealth Edison Company;

MR. BRUCE A. RENWICK
Director, NorthBridge Group, Inc.

SULLIVAN REPORTING COMPANY, by
Tracy L. Ross, CSR

# I N D E X



# E X H I B I T S

| Number | For Identification | In Evidence |
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None so marked.

COMMISSIONER HARVILL: Good afternoon. This is a special open meeting of the Illinois Commerce Commission held pursuant to notice. Present today are Commissioner Kretschmer, Squires and myself, Commissioner Harvill.

Today's special open meeting was noticed as an electric policy meeting to discuss the status of generation and transmission systems in northern Illinois.

This meeting will build upon previous electric policy meetings in that it will form the basis for any market base, rather, last resort mechanism.

Today, representatives from Commonwealth Edison will present to the ICC a status of the generation and transmission systems in the emerging competitive environment. This presentation will focus on the common service territory and surrounding region.

Ms. Arlene Juracek, Vice President of Regulatory and Strategic Services, will speak to the development of the generation market within the ComEd service territory and its future outlook.

Mr. Bruce Renwick, Vice President of Transmission Operations will discuss how the movement into, and out of, and within the ComEd transmission system currently operates.

And, finally, Mr. Michael Schnitzer, Director of The NorthBridge Group will address how RTO developments will further enhance the transmission system of the future to accommodate competition.

With that, I will turn to Ms. Juracek for the first presentation.

MS. ARLENE JURACEK: Thank you. It's my pleasure to be here along with my colleagues to talk about the status of the competitive generation market with a concentration on ComEd's service area but recognizing that we need a regional outlook. So we'll be presenting some regional information as well.

COMMISSIONER HARVILL: Can you move a little closer to the microphone.

MS. ARLENE JURACEK: Sure. If we can get to the first slide.

COMMISSIONER HARVILL: If you can't read it, there are copies outside. Grab a hard copy of it.

MS. ARLENE JURACEK: Okay. As Commissioner Harvill noted, this discussion is taking place in the context of provider of last resort discussions. And provider of last resort, of course, makes sense only when customers are leaving and it implies a competitive marketplace. And we know that switching activity, thus far, in the ComEd service area has been quite vibrant. It has been very active, especially, among larger sized customers.

And ComEd's provider of last resort proposal seeks to further encourage that movement to the marketplace especially by larger customers. And this would be done by changing their bundled rate offer to one that's based on short-term market prices. And in order to do that, there's a presumption that there is a market or that we're furthering a market through this activity.

So the wise question to ask and it has been asked is: Is there sufficient generation and transmission to support a sustainable retail market activity in the Illinois region? So today we are addressing that and it's really an intertwined perspective. Generation and transmission issues go hand and hand as you will hear from our combined three presentations.

So I'll begin and talk about generation. Bruce Renwick will talk about the movement of power into, out of and within the ComEd area. And then Mike Schnitzer will wrap it up by talking about RTO developments which will further enhance the transmission systems on a wider area to accommodate transmission (sic).

So the big take-away message on generation is that sufficient generation is already built or in the pipeline to meet the ComEd control area peak demand for many years into the future. This is the opposite of where we were just not too long ago, but I'll show you through my subsequent slides that we believe that there is sufficient generation.

Furthermore, that generation is going to be a better balanced portfolio. There's been some concern that most of the new generation has been peaking units, but, in fact, when you lay that over the base load generating units that were already in place, it makes sense to balance the portfolio that we've seen in the amount of peaking capacity that we've seen.

Furthermore, there are concerns, obviously, about market power and we'll demonstrate that there are various owners using various types of generation to meet the control area load.

None of this would have been done if the utilities themselves owned the generation. We do have significant independent power producer development in northern Illinois. And, in fact, between 1999 and 2001, we saw 5,000 megawatts of new generation in the ComEd service area with another 3,500 planned for this year, about 3,000 megawatts to be operational for this summer.

Furthermore, there's about 4,300 megawatts of IPP generation in the queue for service by the end of 2004. And the obvious question is, with market prices as low as they are today, how can we be sure we're going to see that 4,300 megawatts actually constructed? When I asked for this information to be compiled it was presented to me that there's actually almost 10,000 megawatts on the drawing boards and this is our assessment. The 4,300, as to what we believe will actually be built and it's based on our information with respect to actual construction beginning or actual equipment being ordered. So there is some uncertainty in this number, but we believe it is a fairly likely number for service by the end of 2004.

When we add this new IPP generation to the generation formerly owned by ComEd including both the fossil and the nuclear units, we can see that we expect over 33,000 megawatts of generation in northern Illinois by the end of 2004. And this level of generation is sufficient to meet the expected, most likely, 50 percent probably load. And that's what that 50/50 load means, that there's a 50 percent chance of being less than that load and a 50 percent chance of being greater than that load. That's your typical planning criteria that we've always used and that we put reserve margins on top of.

So when we look at the load and serve guidelines, we do believe that there's sufficient generation to take us beyond 2010. We've shown up through 2010 on this particular chart between load and capacity.

Now we can't just look at what is within the confines of the ComEd control area. We are connected to nine other utilities through tie-line interconnections and, of course, enhance our reliability and facilitate wholesale power transactions. Our next two speakers will get into more detail on the functioning and the status of the transmission systems.

So, because we do have transmission interconnections we can also count on additional generation from outside the ComEd service area to be part of the grid. And we believe there's an additional 1,350 megawatts coming on-line in the Mid America Interconnected Network before the end of 2004.

And, again, given the significant amount of new generation in MAIN, which would include both the ComEd new generation as well as this 1,350 throughout the rest of MAIN, we believe MAIN's reserve margin will be on the order of 17 to 20 percent, will either meet or exceed that recommended range.

Going beyond MAIN, if we look at MAPP and ECAR, we can also see that there is specific interconnections there and significant generation being built. In 2001 we know that almost 5,000 megawatts of new generation was added in the ECAR and MAPP regions and we expect at least another 10,000 megawatts to be added in ECAR and MAPP by 2005.

Again, some of that generation will be needed to serve new load in the MAPP and ECAR regions, but the point is, with an interconnected system, we will have not only the existing generation but significant amounts of new generation to serve the wider region.

Now, the big question that always comes up, as I indicated earlier, is the generation mix and some concern that so much of the new generation has been combustion turbine peaking units; but we are seeing, particularly, in the queue through 2004 some intermediate combined cycle facilities. And I think this is a really interesting set of circle diagrams here where we compare the 1998 mix of generation with the projected 2004 mix. And we see that by 2004, peaking will constitute about 30 percent of the capacity; intermediate, about 20 percent; and then the baseload split between 29 percent nuclear and 20 percent coal. And we compare this to the 1998 mix which only had 7 percent peaking and significantly greater amounts of baseload capacity. So we're going to have a better profile of available generation to meet the profile of customer's loads as this capacity is added through 2004.

The final issue that I would address is to get at the idea of market power. There has been a concern that so much of the generation is located in just a few players and the last line here really shows that we're moving in the right direction with respect to a diversity of ownership. We list some of the owners of generation in the area compared to the days when it was just ComEd that owned all the generation and you can see, that the 1998 ownership mix only had 5 percent Dominion, 3 percent Southern, and 92 percent ComEd. When we moved through 2004 we see that the Exelon generation is 30 percent, the EME is 28 percent, with Dominion at 9.

And significantly, all of the other generation adds up to 33 percent of the ownership mix and this is ownership mix defined by numbers of megawatts owned by each of the various players.

So we are seeing a diversity of players with a diversity of power types entering the marketplace. We see a sufficient amount of power able to meet, not only, the load requirements, but the reserve requirements. But, of course, all that depends on the robustness of the transmission system.

So what I'd like to do is turn this over to Bruce and he'll talk about the ComEd transmission system and then we'll get to Mike who will talk about the RTOs.

COMMISSIONER HARVILL: Before we do that, are there any questions from the Commissioners for Ms. Juracek?

COMMISSIONER KRETSCHMER: I have a couple.

COMMISSIONER HARVILL: Why don't we do it that way since the material's fresh.

COMMISSIONER KRETSCHMER: Miss Juracek, on page 5 you talk about IPPs and you list the number of megawatts that have been constructed -- will be constructed. What guarantee have we that the megawatts that are being constructed or have been constructed will stay in Illinois? There's nothing that says that an IPP can't build in Illinois and sell that power to Ohio, Indiana, or God forbid Michigan.

MS. ARLENE JURACEK: And that's okay because of the way the electrical system works. If the generation is located in the control area, it actually helps to support the control area load, just because of the physics of the interconnected system. So the local generation will support local voltage control, local regulation and local load following if it's a peaker.

It's important to have sufficient generation within the control area and even though it contractually may be serving load outside of the service area, it's being located here is very important. And actually, Bruce Renwick gets into that a little bit in terms of loop flows and how the power actually flows. Although contracturally, it may be going to Calgary, it's really doing a whole lot of other things in the meantime.

COMMISSIONER KRETSCHMER: I'll get around to talking to him about transmission, I have concerns there; but I have one other question for you. Since California, there has been a variety of discussion about how much generation is needed, who should build it, who should own it. Why should I be reassured that in 1998 you owned 92 percent of generation and now -- or 2004, you'll only own 30 percent when we're hearing discussion from some ports that indicate that perhaps we made a mistake in allowing the utilities to sell off their generation. Tell me why I should be reassured that, indeed, the capacity that's needed will be available at a market clearing price.

MS. ARLENE JURACEK: You correctly started out your question by referring to California and I think you need to look at where you are, what is the model and how the market institution's been set up within a particular area to see if you're making the right decisions. We think that in

Illinois, the way it's been set up, it's actually working and the whole point of this is that Illinois is based on a competitive generation marketplace and if that model is going to work you need a variety of players, both buying and selling.

And what we're trying to illustrate here is, in the context of open access and in being concerned about a mitigation of market power so that there are less price control issues in an open access environment, this diversity of generation is actually a good thing.

And I think what we're seeing this summer, in fact, as prices are tending downwards because there is so much generation and they are, in fact, tending towards long run marginal costs.

COMMISSIONER KRETSCHMER: You brought up a third question I didn't intend to ask, but I will ask it now. All of us have seen, I believe, have seen the press release from representative Novak indicating that postponing an open market may be extended for two years and I'm wondering if there is a tendency for the cost of generation to go down, not up. What guarantee do we have that the customers in Illinois will be benefiting?

It may very well be that the numbers might show that in two years the prices will be lower if the market were already open instead of higher since the market will still be closed.

We're not going to lure any -- as of today, we have no competitors for the retail market here in Illinois, none, even though the market is opening up in a few weeks; what guarantee do we have that customers will be better off two years later, 2006, if, indeed, the cost of production is down and we have a frozen rate?

MS. ARLENE JURACEK: Well, like you, I've seen the press release -- I've seen nothing other than the press release to really understand that the substance of what was proposed today in Springfield. What I do understand is that customer choice is not being foreclosed. I believe the press release refers to a bundled --

a continuation of a bundled rate freeze for two additional years through 2006. There is some symmetry to that, of course, it coincides the rate freeze with the CTC collection period. But the point is, that customers can choose within that period and can have somewhat of an assurance that there will be that bundled rate offer.

COMMISSIONER KRETSCHMER: I understand.

MS. ARLENE JURACEK: If prices are lower, they're going to, actually, have opportunities to switch. We've got things like the mitigation factor built into our formulas where there are opportunities to switch, even with a bundled rate freeze.

COMMISSIONER KRETSCHMER: Why am I still worried? Because as of now we have no competitors for the retail market in Illinois. Why do we have any in 2004 come in if the system that is in place today will be in place in 2005?

MS. ARLENE JURACEK: I think we have seen several competitors who have expressed an interest in the residential market and who have actually begun to do some proactive things, and as soon as they're able to get certified to serve the residential market, I'm sure that we'll see them.

Again, we're in a transaction at the very early days of non-residential choice. We only saw one or two competitors and now we've got eight active competitors, I believe it's seven or eight, that are out there and eventually -- particularly between now and 2004, if we all agree to do the things that are going to further the marketplace, then we should see additional competitors out there.

I know the gas companies, for example, are looking at bundling their gas choice and electric choice programs and there are other expressions of interest from folks, but Illinois was wise in terms of setting up a transmission plan and we need to be patient, I think --

COMMISSIONER KRETSCHMER: I don't mean to -- what's the word, sandbag you, but if you've run any numbers and I'm sure you have; your company has, I would be delighted to get them showing that there will be opportunities and benefits for customers in 2005.

Companies don't usually extend anything because they're being good-hearted. I mean, we all act in our own best interest and I expect companies to do that; but I'd like to see that your own best interest is not in the bad interest of the customers. So if you have any numbers or scenarios that you've run, please let me see them --

MS. ARLENE JURACEK: Okay.

COMMISSIONER KRETSCHMER: -- and plus, if they're not too confidential.

MS. ARLENE JURACEK: Okay.

COMMISSIONER KRETSCHMER: Thank you.

COMMISSIONER HARVILL: Commission Squires?

COMMISSIONER SQUIRES: No, just listening with interest.

COMMISSIONER HARVILL: I have two questions. My first questions goes to your Slide No. 10 where you talk about generation being owned by a variety of entities. And I can't help but be concerned about the 30 percent market share held by Exelon and the 28 percent market share held by Edison Mission Energy, Midwest Generation. That being said, obviously, transmission import capability, that we're going to talk about in a minute, will help mitigate that potential market power that exists by holding such a significant share of the generation market, but have you done any analysis or conducted any analysis that would present results with regard to the effect of that particular concentration of generation?

MS. ARLENE JURACEK: We believe that -- with the concentration of generation as they exist, that market power is mitigated quite significantly. Particularly, if you've got the robust transmission interconnections. And -- you have to look at the mix of the capacity too, the bulk of the Exelon generation is nuclear baseload; the bulk of the Mission Generation is coal based with some peaking capacity.

And so there's a role for folks to play

in assembling the portfolio supplied for the various retailers.

COMMISSIONER HARVILL: I may come back to that after the other presentations. And my other question and I'm just going to follow-up on this in a hypothetical sense as opposed to the specifics of the press release that we've all seen today.

But if we are attempting to transition customers to a mechanism like provider of last resort mechanism that resembles something close to a market based rate, what would be the justification for extending the rate freeze for those same consumers?

Is it in our best interest to move towards a market based rate that will send the proper price signals to consumers rather than artificially putting in place a rate that will go on for an additional two years? Hypothetically.

MS. ARLENE JURACEK: We've differentiated our customers into the larger customers who are actively switching and the smaller customers.

And in our smaller provider of last resort proposal, we have actually proposed for a known fixed price proposal for a number of years. So there's nothing incompatible with a rate freeze with that provider of last resort proposal, of course, assuming that those customers will be able to choose and will have options to choose from.

We believe that there are sufficient mechanisms in the law, either between now and 2004, with the current rate freeze that given the right conditions and the right evidence we could begin to peel customers off and get them better exposed to market prices.

But, certainly, one of the lessons that we saw in California was that when you were able to pass market prices through that customers did respond and were able to help contribute to the demand control.

COMMISSIONER HARVILL: I guess my question is, is your concern with the continuing obligation to serve compatible with a rate freeze for a particular amount of time?

MS. ARLENE JURACEK: I need to take a look at what the proposal actually is.

COMMISSIONER HARVILL: Certainly. I'm putting you on the spot. If there are no other questions, we'll continue on. Thank you.

MR. BRUCE RENWICK: Good afternoon. I'm Bruce Renwick. I'm the Vice President for Transmission Operations and Planning for ComEd, and on those hot days I'm the guy in the hot seat. So, my presentation today is going to focus on how the present-day transmission system operates.

Mike Schnitzer will cover future market and system operations in an RTO.

As background, as I said, I'm responsible for transmission operations; that's all the monitoring, switching, compliance transmission service, operations planning, interchange billing activities. I operate the control area which is the generation/load balance and interchange. And we perform long-term transmission planning, IPP interconnection services and studies and evaluation of transmission service requests and technical studies.

So how does power move on the ComEd system? Really, in four ways. Power moves from generators connected to the ComEd system to loads connected to the ComEd system, internal flow.

Power moves from generators connected to other systems to loads in the ComEd system, imports.

Power moves from generators connected to the ComEd systems to loads connected to other systems, exports.

And power moves from generators connected to other systems to loads connected to other systems. And these are considered wheeling moves.

One of the things you've got to understand about electric flow is, it's a little non-intuitive. If there's a line between the generator and the load, it doesn't mean that all the electricity will go down that line.

Electricity is like wader, it tends to spread out and flow by the path of least resistance.

So, for example, when electricity flows from generators on the ComEd systems or from generators on other systems to load on the ComEd system, some of that electricity flows through other systems. An example of this would be the output of Byron Station. Approximately 28 percent of that output leaves the ComEd system and flows out into other systems and then comes back in on various tie-lines at different locations.

For an import, another example would be, an import from MidAmerican Energy in eastern Iowa coming to the ComEd system, only about 33 percent of that imported amount -- so if I bought 100 megawatts from MidAmerican Energy, only about 33 would come in from the west on the lines across the river, the Mississippi River, out at the Quad Cities. Another 6 to 7 percent would come from Alliant West, which lies to the west of us; but the interesting piece is about 28 percent of that purchase would actually come into our system from the east. It would loop all the way around and come in on 765 or the 245 from the east.

When electricity flows from generators connected to another system to load on another system, wheeling power we talked about, some of the electricity flows through the ComEd system.

An example is Clinton Generating Station located down in central Illinois. About 52 percent of the power that it would generate to load in the Illinois power service territory actually comes into the ComEd system and then flows back out to Illinois Power over the tie-lines. So we've got flows coming in and flows going out.

And another example, a wheeling example, a sale between Ameren and Xcel Energy, Northern States Power up in Minneapolis, even though they're connected by a 345 KB line directly, about 41 percent of that power would actually flow into our system from the south and flow out to the north. So we have flows that come from all directions.

Typical flows on the ComEd system, comEd's generation resources and native load result in a predominantly south to north flow. We have far more generation in the southern part of our system than we do north.

Currently, flows on the eastern and western interfaces of our system typically flow east or west. We tend to be in a net exporter at this point time, especially on a day like today when our loads are relatively low. These flows can either increase or decrease depending on the daily energy market and the requirements of other entities outside the ComEd control area.

My primary responsibility as transmission operations vice president is to maintain the reliability of the ComEd system and the overall transmission grid. To do that, we plan for different ways in which the power moves. As I talked to you just a minute ago, it's a little non-intuitive including contingencies.

To adequately protect the power systems, since it operates, basically, at the speed of light, we need to look ahead and say, what's the next worst thing that could happen to us? And we have to be prepared to be able to deal with that next worst contingency. So I could be sitting here today and everything could look fine; I have a line trip, I have to be prepared to deal with that and make sure I'm not in an overload system, overload condition on another line or a transformer.

ComEd has invested approximately $250 million in transmission upgrades and expansion since 2000.

When evaluating transmission service requests, now, these are requests that we would get from various power marketers that would come in and say, I want to move X number of megawatts from this time to this time and I want to move it from this point -- from the point of receipt to the point of delivery. When evaluating transmission service requests, ComEd has to ensure that the system, ours and the systems around us remain reliable.

ComEd constantly monitors loadings. If you've been out to our office in Lombard, our power office, we have people there 24 hours a day, seven days a week. We monitor generation. We monitor flows across our transmission lines, voltages and we have computer programs that constantly runs stability analysis.

So we're constantly looking ahead. As I said at that next worst contingency to make sure we will be able to function appropriately and we have some help in that area in that we have a reliability authority that oversees us. Currently, that is the MidAmerican Interconnected Network, whose offices are in Lombard. In the future, it will go to the appropriate RTO as they develop.

What if a problem occurs? What are the tools that I have to use to control the transmission system? Well, in the City of Chicago, I have devices called phase shifting transformers and they operate, essentially, like large wader valves only they can reserve flow, too if they have to.

We use them, predominately, on underground transmission lines because underground lines, obviously, were they to have a failure would take the longest to replace and they're the most costly to replace.  So by using the phase shifters, we can pretty well control what the flows are on those lines and not have to worry about overloads.

Outside the City of Chicago on the large lines you see, my tools are a little reduced.  I can use things like dynamic ratings.  All a dynamic rating is, is if I see -- if it looks like I'm going to be on an overload on a line and I look outside and see what's the weather like today.  Is it a nice cool day?  Is there a nice breeze blowing?  That will help cool the conductor.  In a thermal overload, the overheating of the wire itself is one of the things we worry the most about.

Then we can get into curtailing

transactions. The famous or infamous TLR process that the nation -- FERC has put out uses -- TLRs are called by regional reliability authority. I can't call a TLR myself. They are -- we'll talk about them a little bit more in a minute; but they're in my bag of tricks to cut down flow.

And, finally, as I come down to it, I can try to shift the generation resource. If I know I have a constraint, I can try to reduce the generation on one side of the constraint or raise it on the other to balance out the flows.

Again, similar to wadding. If I pump a little more in over here and I don't pump as much in there, I'll eventually level it out no matter how narrow that channel gets.

Transmission loading relief, TLR. When used with other forms of control -- it's used when I can't use a dynamic rating or a phase shifter or an operating step, if you will, to relieve loading -- a potential loading problem.

Again, this is looking ahead at the contingency. It's a command and control process.

It is not economic. It does not distinguish between how much money is going to be made in the transaction and could be shut down. It has to be initiated by the reliability authority. That keeps me, as ComEd, Exelon, from going out and playing games with other people's transactions and it gives the reliability authority the power they need to do it.

Normally, the first step is to curtail non-firm transactions that would have a 5 percent impact on whatever element we thought was overloaded or could potentially overload.

So, again, on that 100 megawatt sale that I had coming in from MidAmerican Electric, if I thought that was overloading part of the line and at least 5 percent of it flowed on that line, that would be one of the transactions that would get curtailed in a TLR step, level 3, okay?

And it goes on, if that gets me out of the problem, if I'm now to a point where the line loading is safe and I can continue to operate there for a long period of time, I'm fine. If it doesn't, my next step would be to curtail what we call firm transactions.

A firm transaction under the definition are sales that are just as inviolable as the sales we have with our own customers.  So when I get to the point where I have to curtail a firm transaction, I also have to look at the generation to load.  In other words, how much power is coming from my own generators that could be going over that line to the ComEd load and I have to curtail that in a pro rata manner to the same percentage, okay?

And, finally, beyond that we're into emergency steps where we would take control of generation and raise it or lower it as the case may be.

RTO implementation and the standard market design will be changing the need for TLRs. That's one of the real pushes behind it and Mike will talk a little bit more about that.

So let's look at TLRs and what they cost.  In 2001 TLR curtailment breakdown, in the eastern interconnection which is basically that part of the country east of the Rocky Mountains excluding Texas, there were 931 TLRs called.

Only one has been called to protect ComEd facilities and it was called in an emergency situation. We had a 345 KB line where a cross arm broke off and the line came down and tripped out and we had to call a TLR, not because we were overloaded at the time, but based on a contingency; we had a transformer that if we would have had another line trip, it would have been overloaded. So we called it there. We did not get into cutting firm transactions on that, it was a non-firm load and we were able to control it.

But the 931 TLRs called in 2001 resulted in 1,469 schedules -- ComEd schedules being curtailed. And a schedule is just exactly what it sounds like, if I'm going to put so many megawatts on the line at this hour and take it off at this hour. It's just like a train schedule, almost. The transaction will flow over this period of time, okay?

Of those 1,469  schedules, 1,291 were exported schedules; in other words, generators in our control area exporting energy to the people outside our control area.

167 schedules were wheeling schedules and that would be generators outside our control area passing energy through the load outside our control area.

And, finally, 11 of those schedules were schedules that were imports, they were from generators outside our load area terminating in our load area, the ComEd load area.  Of those 11, 5 of them were non-economic area purchases and one was a firm area purchase.  So that's part of it.  The other part is to be able to get your energy on the wire and that goes to the evaluation of transmission service request.

As of January 15th, 2002, ComEd had received in excess of 6,200 requests for transmission service from RES's since open access began in 1999.

Approximately 90 percent of these were accepted and confirmed.

Approximately 7 and a half percent were invalid or withdrawn by the person, organization that submitted them.

And 2 and a half percent were refused due to predicted reliability concerns.  Now, 2 and a half percent was about 148 schedules.  Of those 148 schedules, 21 were due to ComEd -- restrictions on the ComEd system either true restrictions on contingencies.  Some of those were driven by our routine maintenance activities where we have to take a line out of service for a period of time to do work on it.

COMMISSIONER HARVILL:  Do you have any information regarding when those occurred and the actual amount of the load that was affected?

MR. BRUCE RENWICK:  No, I do not as of this point.

As of April 1st, 2002, for the year 2002 and looking ahead, ComEd has accepted more than 1,300 RES questions and refused 5 due to predicted reliability concerns. And of those 5, 2 were due to reliability concerns on our system.

So now we get to simultaneous import capability. This refers to an estimated amount of energy at a specific load level that can be reliably imported into our system, okay, from various generations located outside our system.

The actual value of your simultaneous import capability may be slightly less or slightly more than the estimated level due to the various factors which contribute to flows on the network; if we have huge through flows because it's very hot in Wisconsin and we have a lot of power coming in from the south, that will have a negative effect on our problems.

It gives me a general idea as the operator of the system, how much load in the ComEd service territory can be served from external sources -- external generation.

And the amount of import capability needs to be added to the predictable -- predicted available generation within the ComEd control area in order to determine if there are sufficient resources to serve the load.  And I can tell you with the IPP that's come on, it's greatly reduced my personal stress levels.  My doctor is very happy with it.

How much generation is deliverable to retail load in the ComEd control area?  Again, it's the generation within the control area that might not be committed on a given day plus a generation that can be imported into the control area, net any exports we have going on.

Generation within the control area from my standpoint as an operator is more valuable to the generation located outside the control area for some of the reasons, Arlene talked about and also, because I have a better feel for how it will move inside the control area and I know that I'm probably not going to run into transmission constraints on my system.  I might still run into problems with loop flows where it flows out and comes around through other systems because the other system might have a problem; but inside my system I've got a better handle...

Factors contributing to the amount of deliverable power and energy. Well, the location of the generation with respect to a transmission constraint. If all the available generation sits out in a control area to which there's a transmission constraint between it and me, that's not -- my level of comfort start to drop rapidly. I get worry about that.

Transmission configuration. We had a big storm come through, are lines down? Are we doing maintenance work or even our other system's doing this or suffered these types of issues.

Generation status. How much generation is available? How much is gone? How much is out of service for maintenance or repair?

Regional weather patterns. I talked a little bit about a heat wave in Wisconsin and huge flows through to the north; that's a concern, regional -- would be the same going to the south toward Indiana.

Control load -- area load level and net

interchange. If I'm at a relatively high load in my control area and I've got a lot of interchange coming in for some reason, I would be more concerned about it. If I've got a lot of exports, I'm not as concerned because it will tend to -- they will tend to net out over the lines.

And then, finally, the timing of the requests question that I get it from the -- according to FERC rules, I take them on a first come-first serve basis. We look at them, we do a study to determine if they could potentially cause an overload on our system or another and then we can go back and if it looks like there's a potential overload, we can go back and offer the person that would like that contract, opportunities to come in. We've reconducted their transmission lines to allow transactions to flow. We've gone to other utilities and worked with them to allow transactions to flow.

So the more lead time I have on that request, the more I can do about it. If it comes in today for tomorrow, my hands are pretty well tied to try to accomplish it.

In summary, ComEd has an exemplary record of Transmission System operation in terms of operational constraints and reliable service. One TLR and a grand total of 11 schedules affected.  ComEd has been able to accommodate the RES request for transmission service and expects to continue to do so as I talked about the requests.

ComEd does not foresee an issue with the deliverability of power and energy from competitive generation to retail loads.

ComEd is continuously evaluating and planning for the expansion of the transmission service in order to maintain reliable service to its customers.

COMMISSIONER HARVILL:  Commissioner Kretschmer?

COMMISSIONER KRETSCHMER:  Yes.  On page 14 you say ComEd has an exemplary record of transmission system operation in terms of operational constraints and reliable service.

I might remind you that during the past 20 years that this Commission has never denied ComEd or any of the other utilities in the state of Illinois the right to build a transmission system. That is quite contrary to a number of our neighboring states which, obviously, reflects my lack of concern about Wisconsin and Michigan.

So I'm going to go back to page 9 and request you a couple of questions because here's the -- you talk about the TLRs. Of the TLRs called neither -- only one was called to protect ComEd facilities, but the others were called, really, for the benefit of other utilities and I think other states.

MR. BRUCE RENWICK: Yes.

COMMISSIONER KRETSCHMER: Am I wrong?

MR. BRUCE RENWICK: No. You're exactly right.

COMMISSIONER KRETSCHMER: Well, what does that cost us to be sort of the linchpin for other states that refuse to site transmission facilities?

MR. BRUCE RENWICK: I have never gone back and tried to put the dollars and cents together because -- to be very honest with you, that's more of a commercial concern and I tend to be more on the operations side; but it does have a negative effect on how we operate and what we can accomplish, you're right.

COMMISSIONER KRETSCHMER: My concern is, on a going forward basis -- and this not a question but more of a statement -- but on a going forward basis, when we're going to have these huge RTOs I wonder if a study is being done or maybe the utilities should do a study on the costs that's going to be involved to meet the demands of electricity flowing in and out of Illinois. It seems to me that if other states are not carrying their fair burden of having transmission systems, then this state may become a bottleneck and certainly will be negatively impacted from a financial viewpoint. So it's just one other issue that maybe we should be, at least, looking at prior to the huge RTO that the FERC seems to like.

MR. BRUCE RENWICK: Well, I would tell you this: One of the things about transmission that we have to be aware of is, we are all kind of our brother's keeper; we're interdependent. I understand your concern about the RTOs coming in and, particularly, the bottlenecks and other states. They are a problem for us; but one of the advantages, one of my personal hopes for the RTOs is they will take over regional planning and they will come in and force the people that need to build the lines, build the lines.

COMMISSIONER KRETSCHMER: Well, unless there's something I don't know about and that is that Congress has appointed the FERC to site transmission lines, they're going to be sited by states unless that changes and if the states have not deemed it necessary to site them now, what's going to happen in the future?

The only question I want to ask is, if you've looked at or, perhaps, should look at 1,291 exports and 167 wheeling schedules, that you've had to face under the TLRs and to give me some sort of an answer, not today, on what the financial impact of that has been. If you're profiting -- if you're making a profit on these, that's all well and good.

If we are being negatively impacted, financially and then our customers or native load customers, have to foot that bill, that's something I'd like to know.

MR. BRUCE RENWICK: The piece of that that I would know about would be the lost transmission revenues which would be a real small piece. The real heavy financial impact is on the various marketing groups and the other utilities that had to go elsewhere to look for power when those schedules were curtailed; either had to run more expensive generation locally or had to do something else and I have -- I really can't get you that, but I could get the transmission revenue.

COMMISSIONER KRETSCHMER: Okay. If you would and I don't necessarily -- it doesn't have to come from you, but it's important to know the financial impact of other states not doing what they should be doing that -- what we have done.

Thank you.

MR. BRUCE RENWICK: Thank you.

COMMISSIONER HARVILL: Commissioner Squires?

COMMISSIONER SQUIRES: I'm fine. Go ahead.

COMMISSIONER HARVILL: You talked about simultaneous import capability on Slide 11. I was looking for information with regard to what is your simultaneous import capability and how does that related to the retail market that's developing in Illinois? Is there sufficient simultaneous import capability to support what level of retail activity coming into the ComEd service territory?

MR. BRUCE RENWICK: For this summer, our estimate at peak load is about 3,000 megawatts, simultaneous import capability.

But, again, I would go back and say, we have an excess of generation in our control area and so that excess of generation plus the 3,000 megawatts of import capability is what let's me sleep better at night now. I know that I can serve that load out there and I know that if people need to get energy they can get it inside of the control area.

So we're looking on a go ahead basis as Arlene pointed out, at some substantial reserve margins -- excess reserve margins.

COMMISSIONER HARVILL: One of the -- one of my concerns, obviously, is market power as we go forward, not just from Exelon and New Generation, but anybody that has a significant amount of generation.

That being said, I mean, I'm curious about information. If you could provide us at a later date with regard to the various scenarios with regard to simultaneous import capability, not just at the peak, but at other times and also, transmission constraints on your systems and the existence of load pockets that may make portions of your system inaccessible to various imports of electricity at difficult times.

That's really the meat that I'm looking for here if you could provide that.

And I do have one other question for any of the speakers. When this Commission evaluates the existence of market power or market share in this environment, what is the test that we should use to make that evaluation? Should we be looking at simultaneous import capability? I mean, what are the variables that we should be looking at when making that assessment?

MR. BRUCE RENWICK: As an operator, from my standpoint, as I said before, the issues that I see are the availability of the megawatts, either importing them or having them homegrown, if you will, so that they're here and available to us.

I think there's a substantial amount of megawatts out there that are unspoken for or can be imported into the system. And I think it would probably approach or exceed a third of what I anticipate my peak load to be for this year.

COMMISSIONER HARVILL: Okay. Thank you.

MR. MICHAEL SCHNITZER: Good afternoon. My name is Michael Schnitzer and I'm with the NorthBridge Group and I've been active in RTO and standard market design in several regions and have some familiarity with the retail competition program here in Illinois. And I think that's why I'm here, to try and talk a little bit about how those two might fit together and how they might influence each other going forward.

So, I guess on the first page of my presentation, the topics that I'm going to talk about are, first a quick overview of standard market design. The FERC, I think, is beginning to show us the picture that they have in mind as to how the markets within RTOs ought to be organized, I'll talk a little bit about that. It's a huge topic all in itself, but I'll try to summarize that.

And I'll try to talk a little bit about some of the implications of those key features of standard market design for retail access in the ComEd control area and also ComEd's POLR proposals, how they propose to discharge the POLR obligations. So that's kind of the road map here.

The next page, the overview of the standard market design, Staff's white paper has been issued which many of you may be familiar. There's a proposed rule-making promised for some time this summer and some of the key elements of that standard market design are summarized in this slide. The first is regional spot energy markets based on LMP pricing, we'll talk a little bit more about that. Congestion charges for --

COMMISSIONER SQUIRES: Excuse me, Mr. Schnitzer.

MR. MICHAEL SCHNITZER: Yes.

COMMISSIONER SQUIRES: Can you talk just a little bit slower. I'm having difficulty getting it down here.

MR. MICHAEL SCHNITZER: I'm sorry. I will definitely slow down. Unfortunately, the court reporter is too far away to kick me.

COMMISSIONER KRETSCHMER: Get the microphone a little closer as well.

MR. MICHAEL SCHNITZER: Is that any better?

COMMISSIONER SQUIRES: Yes. Thank you.

MR. MICHAEL SCHNITZER: So the first two elements are the spot market's, energy markets using LMP pricing. The second, congestion charges for bilateral schedules, based on location of marginal prices separate and distinct from how the transmission revenue requirement itself is recovered through an access charge.

Integrated ancillary services markets, which may or may not be phased in, depending on the implementation schedule in each RTO.

And financial rights, or some kind of property rights issued by the RTO to provide a hedge against transmission congestion charges, those are sort of the key market elements that the ERC has announced.

And then on top of that, a package of market monitoring and mitigation features which are described in the white paper.

On the next page, just to give a quick illustration of LMP and financial rights, this is a huge topic all on its own right; but I think many of you probably have some familiarity with it already, so let me just try and hit the highlights here.

We have a simple network here. Three buses, it's about as simple as we can make it. And if you imagine in this particular network that contrary to what -- opposite to what Bruce said, the generators are A and B at the north, the load is at C the south, and in this particular formulation, if you imagine a constraint on a B to C link. What you have is -- what LMP does is, whenever there are constraints in the transmission system, power has a different price and a different value on every bus in the network, and so here we've just shown where -- under a particular circumstance where the constraint is binding, you might have an LMP of \$20.00 at B, \$40 at A, and \$60 at C. That's what the FERC has in mind. And these prices will vary every hour, basically, through their structure.

With that, as a foundation there are two ways for parties to transact in this marketplace. They can schedule bilaterally, which is much -- those are the schedules that Bruce was talking about in today's world are the analog, where a party says, I'm going to inject so many megawatts here and I'm going to take them out here, that would be a bilateral schedule.

In which case, they would pay congestion charges for that transaction and in this particular example, if someone had scheduled a bilateral from A to C, they would pay $20 a megawatt hour in congestion. If they had scheduled it from B to C, they would pay $40 a megawatt hour in congestion charges, the difference between the LMPs is how these congestion charges are calculated. 60 minus use for A to C and 6 -- 60 -- excuse me, 60 minus 40 for A to C and 60 minus 20 for B to C. So that's one way to transact bilateral transactions.

And the second is just to buy -- buy or sell any one of these buses at the LMP and people can do either. The structure is designed to be neutral, to provide both; but not to tilt it in either fashion.

And the last pieces, of course, the financial rights which are the hedges against these transmission congestion charges and the holders of those hedges get paid back the congestion. So if somebody held a right between A and C they would get paid $20 a megawatt hour whether they scheduled it or not and if someone held a right from B to C, they would get paid $40 a megawatt hour, whether they scheduled it or not.

So that's a very quick foundation of what the LMP and financial rights systems will look like.

The next page starts to talk about -- okay, let's assume that this gets implemented here over the next couple of years. What will it do for us? And there's four points here on this page and we'll just pick through a slide on each one of them.

The first is, it will give us regional

energy markets with visible spot prices.

The second is it will do a lot to ensure the maximum economic utilization of the grid through better coordination of dispatch and transmission across a broader region.

Third, it will give proper price signals for generation location and transmission expansion -- and Commissioner Kretschmer, I want to come back to your question when I get there.

And then, finally, there will be this package of market monitoring and mitigation features in place as well, that's part of this. So we got one page on each of those.

Starting with the regional spot markets. What FERC contemplates is RTO administered energy markets on both the day ahead and a real time basis. Those are kind of the central building block of the markets. Those will be independently administered; that is, they'll be run by the RTO or the RTO's agent, not by any of the market participants or people who are transmission owners or generation owners. The prices will be visible. They will be visible every hour on every bus. They will be public.

Those markets will be accessible to all buyers and sellers. Basically, there's no restrictions on who can participate, who can buy and sell, they're very open markets as FERC envisions them. And having these spot markets on both the day ahead and a real time basis provides a foundation for forward markets because now you have cash markets against which to close... So that's the theory of the energy markets.

The next page the other benefit, I think, that comes from those energy markets is the maximum utilization of the grid across control areas.

When Bruce was speaking a few minutes ago, he mentioned one of his tools is to use redispatch to deal with transmission constraints and, obviously, he can only do that with the generators that he controls, you know. He can't do it with all the generators and if there's a generator in someone else's control area that if we could get some redispatch there, that would really help, we have limited tools for achieving that today and Bruce, in particular, has a very limited capability because he doesn't control those today.

In the RTO standard market design markets, all generators within the RTO have economic incentives to offer redispatch to the RTO.  It's in their economic interest to do so.

And so we expect and we observe in other markets where LMP is already operating that there's a much better set of tools to achieve redispatch, to get the most out of the grid, generators turning down, generators turning up because as Bruce also said, you know, the location of the generator with respect to a particular constrained element is the key variable.

So, if you got a line overloading and you've got a generator that sits electrically right on top of that line, you know, less from that generator and more from other generators that spread the flow around it's going to get more through that -- more power through that constraint interfacing.

And the RTO gives us much better tools to do that, to optimize generation of transmission through LMP pricing.  There are a couple of consequences to that.  Bruce eluded to the first.

The first prospect is that should reduce the TLRs, where's there's economic redispatch, it can be achieved that TLRs are about to go down and I believe empirical evidence there is that within the LMP markets that the TLRs that originate from those markets are very limited, indeed.

So I think that the experience that we have in the PJM in New York bears out that forecast, if you will, and it could increase the level of imports into ComEd.  The simultaneous import capability, if there's generation redispatch outside of ComEd that has a bearing on what is simultaneously feasible, who will get the benefits of that -- to the standard market design?

The third element here that I'd like to mention is getting better price signals for explanation in both generation and transmission. LMP provides those price signals, even from our simple example, you know, you can see that there were three different -- three very different prices of different buses.

Those prices are valuable in a couple of respects. They will tell generators where they might get higher prices if -- and I think that part is pretty clear; but the other piece that's a little less clear is that the differences in LMP between points determine what more transmission capacity would be worth depending on how often the congestion occurs and how big the price difference is. That's what more transmission capacity is worth.

And what that does is it allows us to -- it gives us an option to think about transmission expansion a little differently and I think in a way that, Commissioner Kretschmer, addresses your concerns that, basically, what we have right now is, we have a mismatch between costs and benefits.

If there's transmission expansion in somebody else's system that's going to benefit through transactions but not their native load, you may find reticence, you know, in places where they're the ones paying for it, but the benefits, may increase somewhere else and that may be part of the phenomenon to which you were referring in your questions and comments.

What we have the option to do once we get standard market design in place is what we call market-funded expansion, which we call participant funding and, Commissioner Harvill, I know you've heard this term in other forums from me, but, in preference, it's rolled into expansion. Which is basically a way to take these property rights that we have in a standard market design and allow people who invest in the transmission system to get the property rights.

The next page is just -- elaborates on that a little bit. Why is that possibility or that new option that we would have had under standard market design important?

The first is, it avoids having local load shoulder the burden for investments that don't benefit them. You know, you eluded earlier to, we don't want to be in a position where Illinois is putting in upgrades and paying -- Illinois customers are paying for them when the benefits go to Wisconsin.

And in this system, you would have an option to where, you know, the people of Wisconsin are the benefiting parties, that they could find the upgrades and get the property rights which is not an option that is very well defined right now.

It will send the right price signals for efficient siting decisions by generators. They know what the transmission consequences are of where they locate.

It can be used to clarify the upgrade

responsibility of new generators, a topic of currently hot interest. And it facilitates this transmission investment and expansion in a way that makes sense and may even address some of the concerns that you indicated earlier, perhaps, not, perhaps I'll hear about that at the question period.

The last of the four -- of the features here is the market monitoring and mitigation. And here's just a quick summary of what FERC is proposing as part of their white paper.

For mitigation, they basically say they want bid caps on generators as a proxy for demand bidding until demand site bidding is sufficiently integrated.

Whatever those words mean, but that's what they said, and must run units subject to mitigation, load pockets and the like, Commissioner Harvill, as you eluded to subject to some kind of a bid or a revenue mitigation as well.

They're talking about the RTO having the responsibility for coordinating generation and transmission maintenance outages.

And then they talked about Independent Market Monitoring Unit that reports directly to the RTO independent board of directors, I think, are the words in the white paper, as well as to the FERC.

And what that unit would do would be to monitor all the markets in the region, transmission and energy and conduct reviews of performance of the markets; to propose rule changes when appropriate with a particular focus on whether or not there is either economic or physical withholding of the supplies, whatever the white paper talks about.

So that's a short tour, I guess, of standard market design emphasizing those elements which may be most relevant to retail competition.

And this last page now says, What might that do?  What might some of the consequences or effect be on retail competition if the standard market design is in place here in 18 months or a few years or whatever?

The first is, we have visible prices and liquid markets available to all customers and suppliers. That are -- again, these are independently administered, you know, not by ComEd, not by the generators, it's the RTO set of markets that will be priced every hour at every bus and the ability of anybody to buy and sell in those markets. That seems to do a lot for suppliers in terms of serving retail customers.

I think it would have some added benefits in terms of ComEd's large customer POLR proposal which rests on short-term pricing of those. And here we would have a vehicle or achieving some of that pricing that was not within ComEd's purview, if you will, it will be an independent RTO market.

It would be easier, even now, to schedule. As Bruce said, he would be hard-pressed to point to any difficulties in the current system of people scheduling the ComEd transmission system, but even so, with the standard market design, all the schedules from the RTO are honored without a request for service. It's just a question of what kind of congestion, pricing, you're going to have; but there's no prequalification or no ticket that you have to have, you can submit your schedule and you don't have to worry further about that.

More efficient use of the grid, a potential for greater import capability, I think we touched on that, you know, at some length due to the extended redispatch capability across the region.

Balancing and ancillary services will come from the RTO and not ComEd, it's that element to the market design that was phased in.

We talked about the improved price signals for economic expansion for both transmission and generation.

I think what we're all interested to hear is development of competitive wholesale and retail markets which minimize total costs and will get a better set of price signals for doing that.

And then the market monitor -- and the market mitigation mechanisms that are proposed are another layer of protection and another forum other than, you know, complaints to FERC, you know, for dealing with concerns about market abuse or market power, and the like.

So that's a quick tour. I welcome your questions.

COMMISSIONER HARVILL: Commissioner Kretschmer?

COMMISSIONER KRETSCHMER: First, I want to identify who you represent and I notice you're the director of NorthBridge Group, Incorporated. What is that?

MR. MICHAEL SCHNITZER: I'm sorry. That's a consulting firm. We're a consulting firm based --

COMMISSIONER KRETSCHMER: I'm not fond of consulting firms.

MR. MICHAEL SCHNITZER: I hope to be the exception.

COMMISSIONER KRETSCHMER: And where are you located?

MR. MICHAEL SCHNITZER: Outside of Boston, Massachusetts.

COMMISSIONER KRETSCHMER: That's my second strike against you.

MR. MICHAEL SCHNITZER: But, your Honor, not Wisconsin or Michigan.

COMMISSIONER KRETSCHMER: My question is a simple one.

COMMISSIONER HARVILL: He's friends with Bill Hogan too, so if that's all --

COMMISSIONER KRETSCHMER: I'm not sure. I'll have to think about that one.

My question is, have you looked specifically at the effect that license plate rates will have in Illinois? What I'm talking about is Illinois is an exporting state and as such, if we are, if our utilities are mandated by the FERC to become a part of the MISO.

Have you looked, specifically, at what the financial impact would be on the utilities in

Illinois, if they have to use the license plate pricing? I understand that's the mandates for five years at this point which I suppose the FERC could change, but five years pricing, have you looked at that?

MR. MICHAEL SCHNITZER: I have not looked specifically at the Illinois situation. I'm familiar with the generation issue of cost shifting and I think that FERC has indicated some flexibility to figure out a way to make these transitions without costs shifts but I don't know the particulars of the MISO debate.

COMMISSIONER KRETSCHMER: I might suggest that you look at the effect on importing states and exporting states. There is a definite financial divide and until such time as there is a more -- what's the word I'm looking for -- fair.

Until the time there is a fair pricing system, I think you're going to find resistance among some regulators from the exporting states who are being negatively impacted by the importing states.

MR. MICHAEL SCHNITZER: I understood. I think that it's unfortunate there's always a way to do it without causing dislocations and it sounds like that way hasn't yet to be found with the MISO.

COMMISSIONER KRETSCHMER: Not to my satisfaction. That's the only question I have. Thank you. I don't dislike you personally.

MR. MICHAEL SCHNITZER: Thank you.

COMMISSIONER HARVILL: You can sleep well tonight.

COMMISSIONER KRETSCHMER: Yes.

COMMISSIONER HARVILL: Commissioner Squires?

COMMISSIONER SQUIRES: Thank you. I enjoyed it all very much and the only question that I would like to ask is, do they have any idea when this is all going to take place? Any guesstimates.

MR. MICHAEL SCHNITZER: They are -- either that or maybe just a little better than that. I think the MISO's implementation schedule for a broad market in conjunction with the PJM market rules and some other kinds of things. I think is based -- they're talking about having the energy markets operational sometime in the later part of 2003, is my understanding of their schedule.

COMMISSIONER SQUIRES: Okay. Thank you.

COMMISSIONER HARVILL: Actually, she took my question. You mentioned the 18-to 24-month time frame. Is it conceivable to have an LMP based system in place for the entire Midwest and arguably for the entire country in that time frame?

MR. MICHAEL SCHNITZER: I don't know about the entire country part of it.

COMMISSIONER HARVILL: Just focus on the Midwest.

MR. MICHAEL SCHNITZER: Right. Parts of the Midwest has got some things going for them in that, they were working along these lines, you know, prior to the FERC standard markets design rule making.

Commonwealth Edison has been a supporter of this kind of system for sometime and I think in the Alliance, MISO conversations which have gone on for some time, there's been some conversation of how to do that.

So my understanding is that, at least, in this region, that may be a reasonable estimate, although, these, you know, these schedules always have some uncertainty in them and I wouldn't want to say that slips are not possible or even likely, but I think that's 2003, end of 2003 is a reasonable point within that range, anyway.

COMMISSIONER HARVILL: Not to turn this into a debate between MISO and Alliance, but how does the standard market design fit in with the current debate with regard to multiple RTOs within the Midwest?

If -- under a hypothetical situation, that the Alliances is allowed to upgrade and administer their own tariff, how will that function with regard to -- how standard market design function with regard to the variability MISO and Alliance?

MR. MICHAEL SCHNITZER: Well, putting aside that issue within the Midwest, one of FERC's goals out of this whole process is to diminish the impact of it seems between the RTOs such that markets do better. I mean, for instance, right now you have two markets, two ISOs that are adjacent, New York and PJM that are both LMP, but not consistent forms of LMP, so there's some problems there.

So I think FERC's goal could very much be to have the systems be similar enough that even between RTOs that these would be internally consistent pricing -- spot pricing and congestion payments.

And so at that point, the boundary of one RTO versus two would not have effects on the energy market piece of things. It might have other effects as Commissioner Kretschmer was eluding to in terms of, you know, license plates and revenue flows and things like that.

But in terms of the operation of the energy market's congestion, I don't believe that

RTO boundaries needs play a large factor here.

COMMISSIONER HARVILL: I'm curious in your opinion of the FERC's standard market design proposal. Are there any aspects of it that you would care to comment are -- and I'm quoting now, Lost rather -- bread to be fed to pigs in the USSR. What are the potential potholes in the system?

MR. MICHAEL SCHNITZER: Well, I think it's -- I think that -- I think the white paper is a good indicator of what the rule making will be, which I have no reason to believe otherwise. I think it's largely a very good effort.

My concerns are more in what's not yet specified then what is specified. I think what is specified is quite good. The two areas that I'm a little bit concerned about how they work out is, first, the one that you elude to is that I think there's a missed opportunity not to specify transmission expansion and a preference for what we call participate funding as opposed to rolled in or to circumscribe the conditions under which rolled in would be appropriate.

More closely and I think -- so that's an area that they've held out for further work. And if they're right, it does need to be worked out and depending on how they resolve that, I'll feel better or worse about that aspect.

The second is the on-going conversation about -- you know, point to point versus flow gate based rights. And the white paper says all the right things. It says flow gates, where feasible, but, you know, we've been debating that feasibility for a long time. I've still got questions in my mind. So as long as it doesn't get in the way of point to point, which does work and is feasible, I'm okay with that, too. Those are the two that come to mind.

COMMISSIONER HARVILL: Because there are people out there who probably know a lot more about this then we do, if there are any clarifying questions and I emphasize the words clarifying questions, you may ask them of our panelists at this time. If you have any, please state your name and your organization.

COMMISSIONER KRETSCHMER: We know as much as they do.

COMMISSIONER HARVILL: I don't know about that. No questions? If not, thank you very much for your time. I appreciate you coming down and spending the afternoon with us and if you could follow-up with us next week or so with regard to the questions that were posed, we would greatly appreciate that.

And if there's no further business to come before the Commission, I will adjourn this meeting. We are off the record.

CERTIFICATE OF REPORTER

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TITLE: ELECTRIC POLICY COMMITTEE MEETING

I, Tracy L. Ross do hereby certify that I am a court reporter contracted by SULLIVAN REPORTING COMPANY, of Chicago, Illinois; that I reported in shorthand the evidence taken and the proceedings had in the hearing on the above-entitled case on the 11th day of April A.D. 2002; that the foregoing 76 pages are a true and correct transcript of my shorthand notes so taken as aforesaid, and contains all the proceedings directed by the Commission or other person authorized by it to conduct the said hearing to be stenographically reported.

Dated at Chicago, Illinois, this 15th day of April A.D. 2002.

TRACY L. ROSS